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Exploration and Production
Shelf Division
Regulatory Affairs Department

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Via Express Mail

Minerals Management Service
Royalty Management Program
Rules and Procedures Staff
Building 85 - Denver Federal Center
Denver, CO 80225

Gentlemen:

RE: NOTICE OF PROPOSED RULEMAKING
OIL VALUE FOR ROYALTY DUE ON
FEDERAL LEASES AND ON SALE OF FEDERAL ROYALTY OIL
62 FEDERAL REGISTER 3742 (JANUARY 24, 1997)

These comments are submitted on behalf of Shell Oil Company and its affiliates, Shell Offshore Inc., Shell Deepwater Development Inc., Shell Deepwater Production Inc., Shell Western E&P Inc. and CalResources L.L.C. This MMS proposal is a radical departure from prior practice and is flawed in its approach to calculating the royalty value of the federal lessor's oil.

The starting point for oil valuation should be the value of the lease product at the lease at the time it is physically severed from the well. The NYMEX future price using a prompt month and the ANS spot price process as suggested by the MMS does not reflect actual value of oil at the lease at the time of production. The market forces which shape NYMEX and ANS value on a daily basis are not directly connected to those market forces which determine value at the lease on a daily basis. Lessees must each day deal with circumstances such as well problems; delivery difficulties related to transport; weather conditions of freeze, storm, and hurricane; and regional oversupply and undersupply problems. These factors and many others like them have a direct and immediate impact on the value of oil as it is produced at the lease. MMS has turned to use of NYMEX and ANS based on a presupposition that no major oil producer is capable of a true arm's-length transaction with a competitor since neither party has a true opposing economic interest. We think this position is flawed and is not based on facts present in the administrative record of the rulemaking. The opinions of experts on futures matters are not substitutes for facts themselves. One must also weigh the circumstance that some of those experts have been retained for substantial fees to espouse those opinions in private litigation. The MMS process for using NYMEX and ANS values clearly may be significantly more or less than the actual value at the time of physical severance of oil. As such, it does not meet legal requirements for determining royalty. MMS itself reached this same conclusion in its 1988 regulations. See Exhibit A attached hereto.

Although we do not agree that NYMEX or ANS is a correct starting point for value, if it or some other value away from the lease is to be used, then MMS must provide adjustment allowances which will realistically correct that value back to the lease. NYMEX applies only to NYMEX defined sweet oil and contains no tables or adjustments for quality or location back to the lease. Similarly, ANS applies only to ANS crude oil delivered to Los Angeles and San Francisco and contains no tables or adjustments for quality or location back to the lease. The present MMS proposal fails to provide adequate adjustments in this regard for transportation, quality, or location differential, as well as any adjustment to reflect the enhanced value of oil in the substantially different risk environment of Cushing, Oklahoma or of ANS at Los Angeles/San Francisco.

In this new proposal, MMS has grafted concepts carried from the presently existing rules based on a value near the lease to a radically different procedure in which royalty value of oil is based on a price at Cushing, Oklahoma, hundreds of miles away from the lease. NYMEX is used principally for paper trades with only a small proportion of NYMEX valued production even actually being physically delivered. The ANS spot prices used are based on a very thinly traded market that is not reliable for valuing production in California or Alaska.

For transportation, MMS has totally rejected the use of published FERC tariffs as a measure for transportation allowance. Instead, the agency has carried over from the existing regulations a utility type calculation in which transportation allowance for a producer/lessee transporting in a producer/affiliate line is limited to depreciation on capital investment, Moody's BBB rate of return on undepreciated capital investment, and operating and maintenance expenses. Although a non-affiliated party moving oil production through the same line is allowed to deduct full transportation tariffs or the full cost of transportation set out in its arm's-length transportation arrangement, the producer whose affiliate owns the line is limited only to utility type deductions. We believe arm's-length transportation arrangements through oil pipelines establish a fair benchmark for determining the cost of transport for the federal royalty portion. This MMS position is unreasonable from an economic point of view and is not supported in law. Federal mineral leases have been repeatedly declared to be no more than ordinary contracts which are to be governed by ordinary contract principles. There are no specific lease provisions or statutory bases which require the MMS to formulate the proposed position. Generally accepted principles of oil and gas law actually provide for a sharing of transportation costs by lessor and lessee. Lessees should, in all circumstances, be allowed to take realistic transportation costs from the market center all the way back to the lease. Otherwise, the lessee owner-affiliate is placed at a competitive disadvantage in the cost of its raw material. Even FERC tariff formulas provide higher rates for transportation.

Since NYMEX is set only for NYMEX sweet crude, the MMS has proposed a series of quality and location adjustments from an index pricing point at Cushing, Oklahoma, to a market center, to an aggregation point, and then on to the lease. However, the process utilized by the MMS in making the adjustments is complex, burdensome, and administratively costly to both lessee as well as the agency itself and is not adequately representative of value at the lease. As presently drafted, quality and location adjustments suddenly end at aggregation points. The quality and location differential to be used at aggregation points is based upon data gathered on a new MMS Form 4415. As discussed in the attachment, this data is based on unreasonably small samples, cannot be proportionately prorated in cases when oil moves beyond the aggregation point, and is never adjusted all the way back to the lease itself. Furthermore, the actual quality of oil production varies from month to month. Historically based data from the preceding year cannot accurately project quality for a current month's production. That is why the MMS Gulf of Mexico Regional Office requires periodic testing for quality at the lease for royalty determination purposes. Therefore, adjustment for quality from St. James/Empire market centers to aggregation points based on historical data is fatally flawed. It is logically inconsistent for the agency to approve utilization of approved spot publications such as Platts to determine quality and location differences at market centers for adjusting NYMEX while refusing to accept the values of these same publications as the starting point for royalty value.

Location differential is intended to recognize transportation and storage costs and variations in risks in order to compensate for the difference in value of oil in two separate geographic locations. The MMS process of using a second unrelated index such as Platts spot to determine location differential between the index pricing point and the market center is not adequately supported by the administrative record. MMS has also presupposed that the market forces shaping each of these separate indices for location differential are identical and that these same forces accurately reflect the lease market at the market center. This approach is also flawed. The calculation of a location differential from the market center to the aggregation point based on data gathered in the Form 4415 is also flawed. The database of the Form 4415 is small and non-representative since it includes exchange agreements between unrelated parties, lessee contracts are not always drafted to conform to the aggregation point and market center points identified by the agency, and the use of historical data from the preceding year presupposes that today's business may be accurately measured by last year's history. Further, the historical average does not reflect a lessee's actual cost to move to the aggregation point. Location differentials suddenly terminate at aggregation points since the MMS proposal does not carry them back to the lease itself. Oil is thus valued at the lease as if it were at the aggregation point ignoring the difference in location between the two points.

Although the MMS has proposed the use of a NYMEX index value which begins in Cushing, Oklahoma, it has made no provision for a market adjustment to this value. NYMEX selects Cushing, Oklahoma, as its point of value because Cushing is located at the intersection of substantial numbers of interstate pipelines and has available to it significant amounts of storage. This substantially alters risks of transportation, storage, and delivery. There is no risk of transportation failure, no risk of well problems, different types of risk for supply, and only a small quantity of oil is ever physically delivered for NYMEX transactions. MMS has not included in the location differential or in any other adjustment an appropriate market adjustment to adequately adjust the NYMEX value for these kinds of risks present at the lease. Similar adjustments are also lacking in the use of ANS at San Francisco and Los Angeles. Instead, the MMS has taken the unreasonable position of alleging that all costs of marketing beyond the lease must be borne by the federal lessee. This position is economically unrealistic and is unsupported by lease terms, statute, and existing case law. Although the lessee is obligated to bear the cost of production necessary to place the product in marketable condition, i.e, pipeline quality, there is simply no authority to require that the lessee bear all costs of marketing the product which are incurred away from the lease. These costs include the types of risks which have been described herein.

In order to implement adjustments from the market center to aggregation points, the MMS has proposed completion of a new Form 4415. The administrative cost for lessees to gather this information and the administrative cost for MMS to digest and average this data is substantial. The validity of this data is questionable. The form requires compilation of data on all exchange agreements between non-affiliated parties. This includes private production as well as production from state and federal leases. Detailed analyses of each exchange agreement will be required to complete each form. In integrated companies, the data necessary to complete the form resides in many different business segments. Real life exchange agreements do not always track the MMS's proposed movement from lease to aggregation point to market center. Instead, exchanges occur from lease directly to market centers or other locations; or from market center to market center; or from geographic location A to geographic location B. Therefore, it is believed that much of the data gathered will be useless for the purpose for which it is being gathered. Since the requirements of Form 4415 are imposed only on non-affiliated exchange agreements, inadequate samples of data will be used to set average location and quality adjustments for lessees. At a time when both industry and government are attempting to streamline to improve efficiency and reduce operating cost, Form MMS 4415 is costly, inefficient, and burdensome. There are substantial questions presented on the legal authority to require routine reporting of non-federal production and to require routine reporting of non-lessee transactions.

Attached are detailed comments on the specific provisions of each of the proposed regulations. MMS publication of an interim final rule in light of the numerous and significant deficiencies in the current rule would be ill advised. Before preceding further on this proposal, MMS must digest, correct and republish another proposed rulemaking for oil.

Sincerely yours,

Peter Velez

P. K. Velez
Regulatory Affairs Manager

Attachments

ATTACHMENT A

INDIVIDUAL COMMENTS ON SPECIFIC PORTIONS OF THE REGULATIONS THEMSELVES

SECTION 206.101 - DEFINITIONS

Allowance - MMS has removed the definition of allowance as a deduction in determining value for royalty purposes. This seems to imply that transportation allowance is the only acceptable deduction from royalty. Traditional oil and gas practice allows other type of deductions depending upon the specific facts surrounding production and, in particular, cost of marketing. Although the lessee may be obligated to place the product in marketable condition, that is, pipeline quality crude at the lease, the lessee is not obligated by statute or regulation to bear the full cost of marketing the product away from the lease.

Area - MMS has removed the phrase "defined limits of" which qualify the description of an oil and gas field. This deletion only further exacerbates the ambiguity and lack of definition in the term.

Arm's-Length Contract - The definition provided for arm's-length contract conflicts with the requirement to use index pricing based upon execution of an exchange agreement within a period two years prior to production. If a lessee meets the definition of arm's-length contract set out in the regulations, then the lessee should be entitled to use the proceeds received from that sale without further disqualification based on execution of a single exchange agreement within a two year time period. Although MMS is granted the option to rebut the presumption of control, the lessee is not also granted that right. The definition should be amended to provide for reciprocal opportunity of the lessee to rebut presumption of control in the 10-50% ownership situation.

Crude Oil Call - MMS has added this definition to the regulation. It is later utilized to require oil sold subject to crude oil calls to be valued for royalty purposes as if it were a non-arm's-length agreement. The underlying presumption is that the crude oil call has somehow reduced the overall value of the oil even in the arm's-length sale. No factual basis has been established for reaching this conclusion. The protection of value which motivates this change is already covered in the existing regulations which requires a lessee to pay royalty on all proceeds received for the sale or disposition of the oil. Its addition to the regulations is unnecessary.

Exchange Agreement - MMS has added a new definition to define and describe exchange agreements. The definition excludes exchange agreements whose principal purpose is transportation. However, the definition as presently drafted is overly broad. Absent specific exchanges made to reduce royalty the fact that one enters into an exchange agreement away from the lease after purchase at the lease is irrelevant to determination of royalty value at the lease. The definition of exchange agreement should be limited to those having impact or origin "at the lease". Exchange agreements occurring at market centers such as St. James/Empire or at refinery gates are irrelevant to determination of value of oil at the lease itself. These agreements are made based on commingled production which is no longer identifiable with a single lease for royalty purposes and reflect market conditions not associated with severance at the lease.

Gathering - The proposed definition of gathering fails to recognize the exception for subsea production which moves great distances from the lease toward shore. At a minimum, the commentary on the regulations should recognize the possibility of an exception recognizing the movement of subsea production great distances toward shore. Previously proposed MMS gas valuation regulations on index did so.

Gross Proceeds - The definition proposed for gross proceeds is defective since it fails to recognize that the payment of royalty based on index value is equivalent to gross proceeds. The definition should clearly state that correct payment of index satisfies all gross proceeds requirements. This was an important point in the proposed gas negotiated rulemaking and is just as important here. Interior has also made a very small but substantial change in dropping the phrase "to the oil and gas lessee" so that gross proceeds is defined as the "total monies and other consideration accruing for the disposition of oil produced." Interior is entitled only to the proceeds received from the sale by its lessee and not for some subsequent disposition of lease products far removed from the lease by an affiliated company. Also changed was removal of the phrase "no cost to the federal lessor". This phrase qualified the value of services performed but only to the extent that the lessee was obligated to perform them at no cost to the federal government. The federal lessor is not entitled to receive the benefit of the value of any and all services performed by the lessee free of charge. Lessee's sole obligation to the lessor is to place the product, in this case oil, in pipeline quality. Costs incurred beyond that, and away from the lease particularly, should be borne by both lessor and lessee. Even the cost of placing production in marketable condition under some circumstances can be associated with the jointly shared responsibility of transportation. As presently drafted, the definition overstates the obligation of the lessee.

Index Pricing - The use of a future price for present day production is inconsistent with the lessee's obligation under current law to pay for the value of production as physically severed at the lease. Future prices are merely a guess at what a hydrocarbon product may be worth at a specified market location at some date in the future. It may or may not have any relationship to the value of the product at the time it is physically severed at the lease.

Location Differential - The definition of location differential describes only the value difference for oil at two different points. It does not explain the difference between location differential and transportation. Nor does it include a provision for a market adjustment to recognize the shift of risks occasioned by use of NYMEX, ANS or other index. In practical application, location differential includes not only an element involving the increased or decreased value of the production occasioned by its actual physical location but it also includes differences in value associated with particular market conditions in effect at the time the location differential applies. These conditions include not only geographic location but weather; political instability in the Middle East or other important oil producing areas; over/under supply of a particular type of crude in a particular geographic location; hurricanes; particular refinery needs; inventory costs; scheduling costs; accounting/overhead cost associated with transportation, ultimate positive or negative effect of blending, etc. This adjustment which we call an index adjustment must occur when value is determined away from the lease.

Processing - The MMS has dropped the definition of processing from the oil valuation regulations. The definition should be included. 30 CFR §202.100(a) requires condensate royalty to be determined on the basis of the oil regulations. In §202.100(a) condensate is described as that condensate separated from gas without processing. Removal of the definition of processing from the oil regulations would be inconsistent with §202.100(a). In addition, there should be some positive statement made in the definition of condensate which captures the concept of §202.100(a) so that both the agency as well as its auditors are clearly keyed to the concept that royalty on condensate separated without processing is to be paid on the basis of oil. The MMS proposal must also be revised to provide directions on how condensate recovered in gas pipelines is to be valued as oil. These directions must include allowance instructions for condensate royalty value as well.

Sale - The definition of sale is inconsistent since it recognizes that the buyer may pay "other consideration for the oil". Transfer of title to oil at one location and the receipt of oil, which is not the same oil, at another location meets the definition of sale if the consideration paid falls into the category of "other consideration for the oil".

Transportation Allowance - The proposed definition for transportation allowance resembles the definition of allowance included in the prior regulations. However, the definition specifically excludes all gathering costs. It is arbitrary and capricious for the federal lessor to deny gathering costs when they are defined so as to exclude subsea production brought great distances to shore. Undoubtedly there is an element of transportation involved in this movement which should be recognized as an exception in promulgating final regulations. This can be done either by including an exception in the regulation itself or by clarifying in the commentary that exceptional circumstances of subsea production may provide for a transportation allowance on a case by case basis.

SECTION 206.102 - How do I calculate royalty value for oil? This definition incorporates the concept of gross proceeds as defined in the proposed regulations. The new definition of gross proceeds failed to include monies and other consideration accruing "to the lessee" for the disposition of oil produced. The MMS's right to collect royalty is based upon the value of the substance as physically severed at the lease and not at some point remote from the lease. It is based upon the proceeds accruing to a lessee not on some price associated with lease products away from the lease. It is only under extraordinary circumstances which have not been factually demonstrated in any way in this proposal that the MMS should be able to propose some type of a net back determination for value. This is particularly true in the arm's-length situation. The entire thrust of §206.102 is inconsistent with the MMS's definition of an arm's-length contract. This is particularly exemplified in §206.102(a)(6) which disqualifies from use of arm's-length gross proceeds any company or its affiliate which has purchased crude oil from an unaffiliated third party in the two-year period preceding the production month. This provision virtually guts the arm's-length provision and leaves it applicable to almost no company holding federal leases. It conflicts with the definition of arm's-length given by the government in the rulemaking and is based upon an arbitrary and capricious presumption that there is something wrong with making a purchase of oil from a non-affiliated party. This arbitrary classification cannot stand muster under any of the statutory bases for assessment of royalty. Although the Secretary is granted great discretion in determining value, that discretion is not without bounds. This provision violates and goes beyond those boundaries. MMS retains, in a subtle but real way, the right to compare proceeds received under gross proceeds and under index pricing and for arm's-length contracts to assess royalties on the higher of the two. This concept is embodied in §202.102(a)(2). This is extremely arbitrary since MMS requires the use of index pricing under (c)(2) if a lessee had a sale of oil to a non-affiliated third party within a two-year period of a production month. MMS must choose one method or the other and make a clear statement that gross proceeds equals index value.

SECTION 206.102(a)(4) - Disqualifies arm's-length gross proceeds if the oil production being sold is subject to a crude oil call. There is no restriction on the crude oil call. Strangely enough, some crude oil calls actually could call for a higher price or an average of several postings. MMS has apparently presumed incorrectly that crude oil calls are always based upon some discount to the value of oil. No factual basis has been established in the rulemaking record to support this a presumption. As drafted, the rule might force oil subject to a call to be valued at index pricing only to later be assessed a higher royalty based upon the MMS's concept of gross proceeds.

SECTION 206.102(a)(5) - This provision appears to require payment of royalty as part of gross proceeds on buy down and buy out proceeds received by a lessee. This provision is in clear contravention of the IPAA v. Babbitt case, slip opinion No. 95-5210 (D.C. App. Ct. 1997). The IPAA v. Babbitt case has clearly established that those proceeds are not paid for the hydrocarbon but are paid for non-production and that royalty is assessable only on the mineral as physically severed at the lease. It is arbitrary and capricious for the agency to promulgate a regulation which flies in the face of the Circuit Court of Appeals' decision which was binding on a larger majority of trade association members who were parties to that case and was based on a test case selected by MMS to resolve the matter.

SECTION 206.102(a)(6) - Disqualifies an arm's-length sale if the lessee or any of its affiliates purchased crude oil from a non-affiliated party during a preceding two-year period from the production month. No explanation is given which justifies this contradiction of the definition of arm's-length given in the regulations to totally disqualify transactions between parties with opposing economic interest. The provision is purely arbitrary and capricious and has no basis in statute. In fact, this provision renders the arm's-length gross proceeds valuation regulation practically inapplicable to any OCS lessee. Only one transaction is required during the preceding two year period in order to disqualify all non-arm's-length transactions from the gross proceeds rule. Again, there is no assurance that the lessee will not be required to pay a higher royalty at some later date even though it was required by regulation to pay on index pricing. Gross proceeds is nowhere in the regulations defined to be equivalent to index value as determined under the regulations. As long as this ambiguity exists, there remains the distinct reality that those parties actually following the regulations promulgated by MMS would be penalized by a subsequent assessment for underpayment of royalty, together with accrued interest, because the proceeds actually received from the sale exceeded that of index. This ambiguity is carried further in §206.102(b)(3) in which a lessee is obligated to base royalty on the highest price he can receive through a legally enforceable claim under his contract. If the arm's-length lessee is required to value oil under index pricing but the value of actually received exceeds index pricing, then the lessee is left in an impossibly ambiguous position merely because the MMS has presumed that all "call oil" and all oil sold under a non-arm's-length contract, if a sale has been made to a non-affiliated third party, is incapable of being a true arm's-length transaction. This is truly extraordinary position for the agency to take based on the record presently supporting the rulemaking.

SECTION 206.102(c) - VALUATION OF NON-ARM'S-LENGTH SALES - This proposal is deficient because it contains no certainty for non-arm's-length sales. In no instance is index ever defined to be equivalent to payment of gross proceeds. However, the lessee is obligated to select either the resale price of its affiliate or use index pricing while the agency retains, under the definition of gross proceeds in §206.101 and under §206.102(e) and (g), the authority to require a higher payment from the lessee. In short, the lessee is placed in the position of after the fact paying royalty either on the resale price of the affiliate or the index price, whichever the MMS may later determine in audit was higher. This would occur because the lessee was required to select one method or the other for all of its oil even though a portion of the oil may be receiving a higher than index price. This provision is arbitrary and capricious.

The MMS in §206.102(c)(2) asserts a right to collect royalty on the proceeds received under the affiliate sale. There is no statutory authority for the MMS to assess royalty on a lease product with no restrictions on treatment, commingling, marketing efforts, transportation, and the bearing of market risks, all of which take place away from the lease. Section 206.102(c)(1) fails to recognize that the lessee may enter into both valid arm's-length sales as the terms "arm's-length" and "sale" are defined in the proposal as well as making non-arm's-length sales to its own affiliate. The underlying presupposition of the MMS is that the lessee is incapable of entering into an arm's-length contract even though the agency defines an arm's-length contract. This is a logical inconsistency and can only be characterized as unreasonably arbitrary and capricious. At a minimum, the agency must be required to chose either index pricing or arm's-length pricing and not leave the lessee in the position of being forced to pay royalty under a system which may later result in an assessment of underpayment and interest. There should be a clear statement in the final regulation that payment under index valuation fully satisfies all obligations for gross proceeds.

SECTION 206.102(c)(2) - This provision will apply to a majority of the production flowing from federal leases because of the exceptions for call oil and for sale of production to a non-affiliated party within a two-year period from the production date and sale to affiliates. The regulation as drafted requires the lessee to select and use one method and only one for the entire year even though some oil is also sold at arm's-length to third parties. This provision would make index pricing the royalty value of a majority of production on federal leases, both OCS as well as onshore. It requires index pricing even if only a small volume is sold to a non-affiliated party or if only a small volume is subject to "call" option.

__**SECTION 206.102(c)(2)(ii)**__ - This provision requires the use of a NYMEX future settle price for domestic sweet crude oil contracts for a specified prompt month. The prompt month is the earliest month for which futures are traded on the first day of the month of production. A NYMEX future price is substantially different from the value of crude oil at the lease itself. As such, the NYMEX price cannot be reasonably netted back to the lease in order to reflect the value of the oil on the day of physical severance at the lease. NYMEX futures prices reflect a whole series of market conditions which do not exist at the lease. The adjustments to NYMEX suggested by MMS simply do not adjust for these market differences. This averaged daily close NYMEX price from the 21st of the preceding month to the 20th of the production month may or may not reflect value on the day of physical severance due to market conditions effecting value at the lease.

"NYMEX" is an acronym for New York Mercantile Exchange. New York Mercantile Exchange is one of the world's largest physical commodity futures exchanges. The NYMEX division trades in crude oil, heating oil, gasoline, natural gas, propane, platinum, and palladium. The NYMEX trading floor is located in New York City. It has 749 individual members with 816 seats in the Exchange, consisting of brokers, bankers, refiners, marketers, and individuals. In its own literature, NYMEX makes it clear that physical supplies of traded commodities are not found in NYMEX offices. Instead, NYMEX traders buy and sell futures contracts. A futures contract is a legally binding obligation to buy or sell a commodity such as crude oil at a specific price and location at some specific future date. For crude oil, NYMEX has a standardized crude oil futures contract. The contract pertains only to the future sale of light sweet crude oil and is usually referred to as a NYMEX Division Light Sweet Oil Futures Contract. These contracts provide for the same delivery point, namely, Cushing, Oklahoma.

NYMEX permits trading in crude oil futures contracts for delivery in the next thirty consecutive months. It also has "long dated" futures contracts including 36 and 48 months prior to delivery. Trading in NYMEX crude oil futures contracts for delivery in a given month terminates at the close of business on the third business day prior to the 25th calendar day of the month preceding the delivery month. As such, NYMEX future prices have no direct relationship to the value of oil on the day of actual physical severance of the oil at the lease in the month of production.

NYMEX futures contracts refer to a NYMEX Division light sweet crude oil. Although NYMEX sweet oil contracts are most frequently regarded as the equivalent to West Texas intermediate, in fact, NYMEX has established that several other types of sweet crude oil are deliverable in order to fulfill actual physical delivery of a crude oil futures contract described as NYMEX sweet. In addition, several foreign crudes, considered to be chemical equivalent, are accepted as NYMEX sweet. However, there is no table of adjustments published by NYMEX which adjusts for sulphur content and gravity and location differential at geographic locations of a lease. Instead, NYMEX applies only at Cushing, Oklahoma. Under current practice, both the posting of producers and the spot market prices of others recognize differences in sulphur content and gravity and make adjustments to value at a specified pricing point for these components. In addition, spot prices also contain adjustments for geographic location.

NYMEX crude oil futures contract prices, like other commodities, are determined in open and continuous auction on the NYMEX exchange floor in New York City by traders acting on or on behalf of anonymous sellers and buyers. This auction process is referred to as "open outcry". The process is similar to an auction except that there are numerous sellers as well as buyers present at the open outcry. Sellers compete with each other to sell, driving down offering prices, just as buyers compete with each other to buy, driving up bidding prices.

What is bought and sold through NYMEX is not crude oil itself but futures contracts, that is, agreements to buy and sell the commodity at a certain place at a future time. The place of delivery is specified as Cushing, Oklahoma, with the crude to satisfy the contract described as NYMEX light sweet. However, in fact, very few physical deliveries of oil are ever made under NYMEX futures contracts. A NYMEX futures contract is a commodity instrument, not an actual barrel of crude oil. On a good trading day over 150,000 contracts may change hands. The barrels of crude oil traded under those contracts would greatly exceed all of the crude oil produced per day on average in the United States, including both private as well as federal leases. One of the major purposes of trading in future contracts is to engage in hedging.

Buyers and sellers trade in future contracts to lock in the price and thereby avoid the risk that the market price will change significantly in the future. As time passes, the holders of future contracts have numerous means of actually "closing out" their futures position without actually taking possession of the oil commodity at the time and place specified in the futures contract. Very little physical delivery of oil occurs as a result of these futures contracts. The governments of some oil producing nations, such as Mexico, Norway, and Columbia, trade in futures contracts in order to hedge, that is mitigate, financial risks associated with oil production revenue. Even some states of the United States have developed similar hedging programs.

In addition to hedgers, other major participants in trading NYMEX futures contracts include speculators. Speculators take positions in futures contracts, not as a hedge against price changes of commodities that they will actually sell or purchase at some future location and time, but in hopes of timing the market advantageously in making a profit. Speculators try to buy low and sell high.

NYMEX is believed to be dominated by speculative interest. With respect to participation in NYMEX, in 1996 producers of crude constituted only 3% of the market; integrated oil companies, refiners, and marketers represented a combined 25% of the market; and speculative interests constituted the remaining 70%. These speculative interests include traders, financial institutions, and other speculators on the trading floor.

As is obvious in this description, the value of NYMEX crude oil futures contracts is influenced by forces not present in the lease market. There is a substantial difference between a commodity benchmark and physical wellhead supply value. Physical delivery is not a primary rationale behind trade in futures. Instead, price considerations predominate. The very ease with which future contracts are traded and closed out gives them added value over the cumbersome physical barrel at the wellhead.

The NYMEX futures contract is a structured trading instrument with built in administrative protections, including financial surveillance by NYMEX, audits, and the maintenance of financial integrity of futures contracts through the enforcement of position limits and margin requirements. These features enhance the value of NYMEX contracts, adding a de facto, built-in premium to NYMEX prices.

The price of futures contracts is affected by matters involving timing and the prices of other futures contracts pertaining to delivery for the same period. Timing is an essential element with futures market participants earning profits by determining when to buy and sell oil over the life of a futures contract. In short, these futures prices have little or nothing to do with the value of physical oil severed at the lease. All NYMEX futures contracts provide for delivery at Cushing, Oklahoma. Cushing has more than 24 million barrels of crude oil storage and more than a dozen major pipeline linkages and interchange connections for mid-West destinations. Cushing's substantial storage facilities and vast interconnected pipeline systems gives future contracts specifying Cushing as the delivery point an added value from a physical standpoint. The seller of oil at Cushing is at a central distribution point with access to a large number of buyers which gives an added value to his crude. In contrast, the vast majority of crude oil actually physically severed and produced in the Gulf of Mexico and onshore does not benefit at the lease from this infrastructure and the pool of buyers that is present at Cushing.

Although various entities valuing crude oil at the lease may be aware of NYMEX crude oil futures contract prices, there is no simple mechanistic relationship between a NYMEX futures price in New York City for delivery at Cushing and the value of specific non-NYMEX crude oils at the lease in the Gulf of Mexico or elsewhere. In fact, NYMEX contains no table for adjustments of quality, sulphur, and gravity. In addition, there is no risk of delivery caused by pipeline capacity restraints or breakage since delivery is at Cushing. Prices of non-NYMEX sweet crude cannot be directly related to NYMEX. To bridge this gap, MMS has suggested mixing apples and oranges by adjusting NYMEX values through the use of spot, wet physical barrels at major market centers. This bastardized combination cannot withstand scrutiny. If MMS is willing to use the differential in base price at spot between various crudes at St. James/Empire as a deduction from NYMEX base value at Cushing, why would not the base spot value of the commodity at St. James/Empire not be the correct value. Stated another way, if the differential in base spot value is valid, then why would not the base value itself be valid? Although we do not agree that either is correct, they illustrate the arbitrary nature of MMS's proposal.

Built into the NYMEX future price is a premium. This premium includes consideration of the ease with which futures contracts can be traded compared to the trading of physical barrels of crude oil; the built in structural protection provided by future contracts reflecting administrative protections, i.e. credit worthiness, regulated market; and the vast differences between marketing crude oil for physical delivery at Cushing and marketing hundreds or thousands of miles away at a lease. Speculative forces also have a major impact on the value of NYMEX, but they have little or no role in valuing oil physically severed at the lease itself. For these reasons, the value of crude oil severed at a lease does not move in conjunction with NYMEX future prices.

MMS's proposed adjustments do not even approach accounting for this kind of premium that is built into the NYMEX futures contract. MMS's location quality differential, which is intended to adjust the value from the market center to the aggregation point, is a fixed value based on prior years historical data. This approach assumes a mechanical relationship which does not exist and does not reflect the actual cost paid in the month of physical severance by a lessee. This approach deprives large producers moving through an aggregation point to market center of the actual transportation costs incurred to move the oil. Quality of crude varies from month to month. That is why the MMS Gulf of Mexico operations requires periodic quality tests. Averaged quality data based on last year's historical data has no relationship to today's quality of production. Basing value for royalty on "one" fixed quality average is arbitrary and capricious.

Under the proposed regulations, the MMS is attempting to impose royalties on a value different than the value of oil production as physically severed at the well. To the extent that MMS attempts to assess a royalty based on the value of crude oil after the production is removed from the lease premises to remote locations, the MMS exceeds its statutory and contractual authority to do so. This is true even though the Secretary of Interior has great discretion to determine the value of production for royalty purposes. This discretion is not without limits. The Administrative Procedure Act, 5 USC §551 et seq., prohibits the Secretary of the Interior from acting in a manner that is arbitrary, capricious and an abuse of discretion or not otherwise in accordance with law.

MMS's regulatory authority to determine the value of production for royalty purposes is governed by statute. Under §8(a) of the Outer Continental Shelf Lands Act (OCSLA), the payment of royalty is set at a percentage "in the amount or value of the production, saved, removed or sold from the lease". The Mineral Leasing Act similarly requires the payment of royalty at a percentage "in the amount or value of production removed or sold from the lease". 30 USC §226(b). Congress, in promulgating the OCSLA, recognized the need for fair leasing provisions which incorporated commonly understood terms of leases developed and in general use in the industry after a long period of trial and error. Courts have relied on this statement of Congressional intent to conclude that the Department of the Interior cannot reverse long standing policies in existence prior to the enactment of the OCSLA because those policies were acquiesced to by Congress in enacting the statute. Amoco v. Andrus, 527 F.Supp. 790 (E.D. La., 1981). H.Rpt., 278, 81st Congress, 2d Sess. at 9-10 (1950). Therefore, MMS cannot substantially deviate from the general common law principles applying to market value royalty clauses that were in effect at the time leases were entered.

The focal point for valuation by MMS has historically been at the wellhead, that is, the point at which production of oil and gas is severed from the ground. As far back as 1947 in United States v. General Petroleum Corp., 73 F.Supp. 225, 254 (S.D. Cal., 1947), the court interpreted the application of the Mineral Leasing Act to the valuation of natural gas to hold that natural gas royalties were payable on gas as produced at the well. **"It is the value of that gas which must be determined."** The Interior Board of Land Appeals (IBLA) has more recently affirmed that point. Mobil Producing Texas & Mexico, Inc., 115 IBLA 164, 171 (1990). In this appeal, IBLA held that normally gas is sold and valued at the wellhead for royalty purposes. This principle was enunciated again in the Marathon LNG case. Marathon Oil v. United States, 807 F.2d 759, 765 (9th Cir., 1986). Marathon Oil v. United States, 605 F.Supp. 1375, 1386 (U.S.D.C. Alaska, 1985). Although the Marathon case involves a net back of liquefied natural gas from Japan back to Alaska, in that case Interior recognized its obligation to value the product at the time of production at the lease. In those cases where MMS has attempted to impose royalties on something other than the value of production saved, removed, or sold as in Diamond Shamrock Exploration Co. v. Hodel, 835 F.2d 1159 (5th Cir., 1988). The courts have required the agency to assess royalty on physically severed production at the lease.

A federal oil and gas lease is no more than an ordinary contract. Parties to that contract are entitled to rely upon the terms of the lease they entered. A typical OCS lease form provides for royalties to be paid on the "amount or value of production saved, removed, or sold **from the leased area**". (Emphasis added.) A phrase the Department has used for OCS leases since its first Form 4-1255 was issued in May 1954. The language from a typical onshore lease form provides for royalties on the "production removed or sold from the leased lands". In Lynch v. United States, 292 U.S. 571, 579 (1934), the court held that contracts entered into by the government such as oil and gas leases are governed generally by the law applicable to contracts between private individuals. As such, the government is bound to the terms of its contract just as would be any other private lessor. Rosebud Coal Sales Co., Inc. v. Andrus, 667 F.2d 949 (19th Cir., 1982). Therefore, the MMS's movement of a royalty valuation point downstream of the lease in order to capture the value of crude oil at a location away from the lease is contrary to the MMS's statutory authority and is in violation of the terms of the oil and gas leases that the federal government has entered. In addition, use of index futures based pricing violates the terms of the lease contract and the mineral statutes by imposing a value based on a speculative future assessment rather than assessing value on the hydrocarbon at the time of physical severance from the lease. The agency has no authority under statute to do so. In fact, it was for just this reason that MMS rejected consideration of NYMEX pricing in the 1988 regulations. (Attached are FOIA documents produced from the 1988 rulemaking, marked as Exhibit A.)

The second is, to a degree, a derivative of the first. In granting transportation allowances, the Department historically has limited the allowance to the cost of moving production to "the first potential market." *Id.* at 127. See also ARCO Oil and Gas Co., 109 IBLA 34, 38 (1989) ("transportation costs have been disallowed where the costs claimed were for transportation beyond the point of the nearest potential market"). The rationale for this restriction is that the further from the wellhead the Department goes when valuing production, the more difficult it is to identify the proper wellhead value.

(The Department's concern was over having to give too much of an allowance for transportation, so it cut allowances off at the first possible market. Ironic, in light of the Department's current proposal.)

The third is to consider Congress' treatment of the issue in the 1978 amendments to the OCS Lands Act. There Congress added Section 27 to the 1953 Act, addressing federal purchases and sales of OCS production. To increase the government's access to crude oil and natural gas, Congress supplemented the Secretary's right to take royalty in kind, 43 U.S.C. §1353(a)(1), with a right to purchase up to one-sixth of the lessee's production. This right, however, could be invoked only if the lessee's royalty rate was less than one-sixth, for royalty volumes are "credited against the amount that may be purchased under this subsection." 43 U.S.C. §1353(a)(2). The purchase right, therefore, was structured to give the Secretary control over barrels in kind as if he held at least a one-sixth royalty on all OCS leases. [leg. hist.?] This statutory purchase right thus mirrors the lessee's obligation to pay royalty in value: in each case, one is paying the other for the right to have barrels of oil. And when the Secretary exercises this purchase power, his duty is to pay the lessee "the fair market value at the well head." 43 U.S.C. §1353(a)(2).

In fact, an active lease market does exist that is separate and distinct from markets remote from the lease. As the MMS knows, Professor Joseph Kalt of Harvard University testified on January 16 and 17, 1997, in the class certification hearing in Engwal v. Amerada Hess, et al, C.B.-95-32, 5th Judicial District, County of Chaves, New Mexico, that the transactions at the lease level demonstrate that localized supply and demand factors influence the market value of crude oil at the lease. Active lease markets are demonstrated by activities of Scurlock Permian Corporation. See their comments dated April 17, 1997, supporting the existence of an active lease market. These market values significantly fluctuate with supply and demand factors specific to individual leases, crude oils, and particular transactions. Supply and demand factors differ at the lease level as contrasted to trade or market centers which use NYMEX or

P-plus as a valuation methodology. Therefore, their use could result in either huge under or overpayment of royalty. Furthermore, as discussed previously, NYMEX value reflects enhanced value added to the crude oil. The sources of this added value are the downstream marketing functions which include the development of marketing information; expertise regarding types of crude; customer preference for crude oil; commodities trading; regulated commodities market which provides for secured transactions and policing for credit worthiness; and lack of risk of pipeline spills and storage and capacity restraints. Although the MMS itself has recognized that appropriate location and quality adjustments needed to be made to NYMEX future prices in order to arrive at the fair value of a barrel of oil physically located at the lease where it is severed, the MMS also recognized that this would be extremely difficult because location quality adjustments needed to derive lease value involved considerable administrative effort for all involved. For this reason, MMS has actually asked for comments suggesting alternatives to value federal oil in the vicinity of the lease. The differences between the physical lease market and the NYMEX future commodities market cannot be quantified with any degree of precision. An adjustment to the price received for delivery of oil at Cushing to reflect the value of the oil at the lease where it was produced must consider many factors. For example, risk. The price obtainable at Cushing will be different than the price obtained at the lease because there are different risks to be assumed and managed in two different types of markets. For example, physical severance includes assumption of the following risks:

1. Risk of inventory loss, namely pipeline loss, pipeline misallocation, measurement variations, physical pipeline breaks, or truck spillage.

2. Environmental and safety risks.

3. Risks associated with facility investments, such as over capacity of pipelines or lack of transport capacity or time needed to construct pipeline infrastructure.

4. Price and timing risks such as spot market versus term contracts, NYMEX versus spot market, and price fluctuations.

5. Credit exposure and risk of purchaser's credit worthiness is present in oil sales but is fairly controlled in the NYMEX market.

6. Performance risks such as fire, explosion, weather, capacity, and well problems.

None of these risks are compensated for in published differentials that MMS will accept between NYMEX at Cushing and value of oil at the lease.

Other factors that should be considered are different supply and demand forces that operate in the NYMEX futures commodity market and the lease market. In the physical delivery market, regional supply and demand factors and weather such as hurricanes and pipeline breaks can have a radical and immediate impact on physical deliveries and on prices while futures prices are set by prices bid during a portion of the preceding month and for only a portion of the present month during a time when these factors are unknown.

Many of the factors for which adjustments should be made have been ignored or are arbitrarily limited in the MMS's proposed valuation scheme. The MMS proposal plainly does not allow adjustments for the out of pocket costs that a lessee would have to incur in order to sell a physical barrel of oil for a NYMEX future price. The MMS proposal also fails to account for the quality difference that exists between a particular severed lease barrel and an actual NYMEX future contract barrel. One major gap is MMS's failure to adequately compensate the lessee for transportation under NYMEX index conditions. Although MMS recognizes transportation as a major adjustment, it has failed in this current rulemaking to provide for a change in transportation calculation to reflect real costs to a lessee. Instead, it has rejected tariff s even though the Director herself has not found them to be unreflective of costs. See, January 18, 1997 Director's decision Shell Offshore Inc., MMS-94-0697-OCS.

Further evidence of the MMS attempt to hold on to the concept of gross proceeds is the retention of the limitation on gross proceeds which has been grafted on to index pricing. Again, Shell urges that if MMS wishes to adopt some type of index pricing that it should be made the equivalent of gross proceeds and that limitations imposed on gross proceeds should not be grafted on to an index approach.

SECTION 206.102(c)(2)(i) - MMS admits here that the value of crude is to be based on a daily NYMEX future settlement price at Cushing, Oklahoma. There is no demonstration factually that this price equals the value of oil based on physical delivery at the lease on the day the oil is severed as required by statute. See, MMS's own discussion of this issue in Exhibit A. Therefore, this proposal is arbitrary, capricious, and not supported in law. NYMEX also contains no ready reference table to adjust either for quality or location differential. NYMEX also contains no readily available method for determining a transportation allowance from the index pricing point at Cushing, Oklahoma, for the Gulf of Mexico to the market centers at St. James/Empire and then out to the lease.

SECTION 206.102(c)(2)(ii) - For federal crude oil produced from California and Alaska leases disposed of under non-arm's-length sales contracts, the proposal would use as its starting point for valuation "the average of the daily mean Alaskan North Slope (ANS) spot prices for the month of production published in an MMS-approved publication". The MMS reasoned that average ANS spot prices for valuing California and Alaska federal oil production is the best starting point for valuation because: (1) production is isolated; (2) ANS represents large volumes of oil delivered in to California for refinery feedstock use; (3) MMS consultants support ANS spot prices as best reflective of market value; and (4) using NYMEX with adjustments for California and Alaska crude oils would be difficult.

However, using an average ANS spot price is not appropriate in valuing federal crude oil produced in California or Alaska for several reasons. First, the published prices may not be reliable because the ANS spot price is based on a thinly traded market. The Thomas Affidavit attached to the comments of the American Petroleum Institute demonstrates that very few spot ANS contracts are executed monthly. Indeed, in some cases, one party alone influences the quoted spot price. As a result, the prices quoted to trade publications may not be based on executed contracts and, therefore, may not reflect the market value of ANS crude oil.

Second, ANS is a declining market. This annual decline in production will only further limit the number of ANS transaction conducted monthly, further aggravating the unreliability of the quoted average ANS spot price.

Third, the Associate Director of the MMS in 1987 concluded that spot prices do not capture the quality and location differentials of different crudes and are only available for a few crude oils. See Exhibit "A" attached. For example, the quality of ANS crude is significantly different from California OCS federal crude oil at Shell's Beta Unit. Whereas, the API gravity of ANS is approximately 28° API gravity with a 1% sulfur level, Shell's Beta Unit has a gravity of 16% and a sulphur of about 3%. Yet, under the proposed regulation there is no adjustment for the quality differential between the California OCS crude and the ANS spot price when the California OCS crude is sold at a market center. Because of the quality differences, the ANS spot price plainly does not reflect the quality of the California crude oil being sold in San Francisco and Los Angeles.

Finally, while the ANS methodology is certainly questionable with respect to valuation of the California production, it makes absolutely no sense to apply the methodology to federal royalty oil in Alaska. The crude oil produced from federal leases in Alaska is produced from leases in the Cook Inlet (about 5000 barrels per day). The Cook Inlet crude oil, which is qualitatively quite different from the North Slope crude, is delivered to the Tesoro refinery located at Nikiski, Alaska where it is refined. Tesoro then sells the refined products in the local Alaskan market. To value the oil, which moves only a few miles from the point of production to the Tesoro refinery, by referencing sales of dissimilar crude oil that take place more than 2000 miles away is nonsensical. To do so would require the backing out of phantom transportation costs, as well as making quality adjustments to account for the considerable differences between North Slope crude and Cook Inlet crude oil. Additionally, there would have to be a determination about whether to use the landed prices and transportation costs to San Francisco or Los Angeles since none of the Cook Inlet crude oil goes to either location and, in fact, never leaves Alaska.

In sum, the use of the ANS spot price as the beginning point for valuing California and Alaska federal crude oil for royalty purposes simply does not work.

In contrast to its proposal to use NYMEX pricing at a basis for evaluating crude produced everywhere except California and Alaska, MMS has proposed to use ANS crude oil spot prices for delivery in California as the basis for pricing California and Alaska crudes. An obvious initial weakness in this proposal is the MMS failure to discuss the size of the ANS market when it emphasized that NYMEX deals with "a widely traded domestic crude oil" and "there is little likelihood that any particular participant in NYMEX trading could impact the price." Elsewhere MMS has referred to the "sheer volume of future contracts traded on the NYMEX" to support their position.

The only reason given for using spot prices on the west coast instead of an adjusted NYMEX is the "difficulty in making meaningful adjustments from the NYMEX price." Shell submits that the notion of difficulty in making meaningful adjustments infects the NYMEX proposal and is not resolved by adopting ANS spot for the west coast. MMS does say that large volumes of ANS crude are delivered to California, but Shell is uncertain what portion of that volume is sold at spot prices, and the MMS record contains nothing but unsubstantiated assertions. Shell's best estimate is that less than five percent of the volume affects the determination of the spot price. The alleged validity of and safeguards for NYMEX pricing are not present and the point is ignored by MMS.

The MMS does note that the west coast markets are geographically isolated and that the distance from the mid-continent markets causes a problem, but that does not prevent them from proposing NYMEX adjustments from Wyoming and Montana which are hard to consider as geographically proximate to Cushing, Oklahoma.

This appears to be an irreconcilable conflict. Shell contends that neither the ANS for California nor the NYMEX for elsewhere is appropriate, but it cannot conceive of an intellectually honest evaluation that can support the correctness of both approaches.

The same defects related to allowance of proper adjustments and deductions and recognition and the wide geographical range of production locations discussed with respect to the NYMEX proposal also apply to the west coast proposal.

SECTION 206.102(c)(4) - MMS states here that it will announce publicly those publications for which adjustments to NYMEX can be determined. However, MMS does not explain factually how differentials and base prices in, for example, Platts spot may be used as a deduction from NYMEX futures so as to arrive at an acceptable value for NYMEX at the market center. How can the agency accept a differential in base prices of different qualities of crude from another index for differential purposes but not accept the base price itself? In other words, if the differential is valid, then the base prices of Platts should also be equally valid. Furthermore, there is no demonstration made in a factual record that it is appropriate to offset a futures price with some type of a spot price to adjust for physical delivery at a lease. Spot prices are published at onshore points. MMS has not demonstrated any relationship to value at the lease. Publications of these MMS approved periodicals reflects one of the major weaknesses of the use of

NYMEX, that is, it is not related to the lease market and the MMS must make some convoluted attempt to force a related adjustment.

SECTION 206.102(d) - In this section MMS retains the right to require preservation of data and to assess royalty on a different value if it determines the reported value was incorrect. This again returns to the issue of gross proceeds versus index value. Under this provision, MMS would be allowed, under the definition of gross proceeds as proposed to track the ultimate disposition of the hydrocarbon to attempt to assess royalty on its downstream disposition if that were to the advantage of the federal lessor. This type of provision is unconscionable since the federal lessee is required to apply the index pricing in almost all cases on federal leases because of the call provision and the purchase or sale within two years of the production month requirement. Furthermore, many of the exchange agreements referred to do not involve the MMS's lessees. There is absolutely no requirement imposed by FOGRMA or Royalty Simplification Act for a non-lessee to be required by the MMS to retain records. There is no authority for the federal lessor to impose a routine record filing and retention requirement on a non-lessee under any of the applicable provisions. There is a vast difference between an alleged right to review records which may or may not already exist and the imposition of a requirement to routinely prepare and submit reports to the Department of the Interior. Even the requirement to routinely review non-lessee records has been contested and, in fact, is the subject of a pending appeal by various producers. 30 CFR §207.5 imposes an obligation only upon the lessee. The lessee cannot be obligated to keep and maintain records which are not in its ordinary business and subject to its control. The non-lessee cannot be obligated by MMS to make those filings.

SECTION 206.102(e) - This provision overstates the extent of the lessee's obligation to bear all costs relative to marketing of hydrocarbons. Lessor and lessee have no dispute that, as a general requirement, the oil must be placed in marketable condition at the lease, which for most leases means pipeline quality crude. However, even this rule has exceptions when the conditioning required exceeds that ordinarily required in the field, lease, or area. The prior version of §206.102(i) more closely reflected a lessee's obligation since it dealt only with placing the oil in marketable condition. In addition, it recognized that a requirement that the lessee pay additional value if he was proceeding under the gross proceeds rule. Again, there continues to be confusion about whether gross proceeds applies or does not apply to index pricing. This change in the marketable condition rule appears to be an attempt by the MMS to graft on to the index pricing rule concepts which were applicable to gross proceeds. The agency must make a decision whether it intends to abide by index pricing which for NYMEX already includes unrecoupable costs of the lessee to which it is trying to graft further assessments for reimbursements. The duty to market for the mutual benefit of the lessor and lessee does not carry with it a duty to market for the lessor at no cost. The duty to market has never before been viewed as embodying a concept that marketing must be done by the lessee for free. Professor Kuntz in his treatise states:

> "After a marketable product has been obtained, then further costs in improving or transporting such product should be borne by both lessor and lessee." (See "A Treatise on the Law of Oil and Gas", Vol. 5, Sec. 39.4, page 299 (1989).

A pivotal determination of who should bear these cost is governed by whether the cost is properly identified as production cost or whether it is properly identified as a marketing cost. Lessees traditionally bear production costs, but lessor and lessee share marketing cost proportionately. The source case of <u>California Co. v. Udall</u>, 296 F.2d 384 (D.C. Cir., 1961) stands solely for the proposition that the federal lessee must bear cost of placing the product in a marketable condition. The <u>Udall</u> case involved dehydrating and compressing the gas to a basic pipeline quality. The <u>Udall</u> case which is the general source of the marketable condition rule specifically excluded costs of transportation away from the lease and therefore implicitly excluded other costs which might be incurred away from the lease. There is no statutory authority for the Secretary to assert an obligation of marketing free of cost to the federal lessor when charges and expenses are incurred away from the lease. In the context of NYMEX as a royalty value, it is particularly unreasonable, arbitrary, and capricious for the government to attempt to base value on a futures price which MMS's own administrative report on the recent gas royalty in-kind program indicates includes unrecoupable cost incurred away from the lease. Not only does this Subpart overstate the rule, but it should actually be reworded to provide for some type of marketing adjustment to account for market differences as described above in utilizing a NYMEX futures price.

MMS's position is that the law is "well settled that marketing expenses necessary to market production from a Federal lease must be performed at no cost to the lessor." Amoco Production Co., MMS-92-0552-OCS at 4 (1996) (citing California Co. v. Udall, 296 F.2d 384, 388 (D.C. Cir., 1961)). But the precedents indicate that the more principled view is more favorable to lessees.

California Co. (Calco) concerned a federal lease in Louisiana's Romere Pass field. Calco sold natural gas at a point within the field to a pipeline for 12 cents per mcf, after Calco had removed excess water vapor and compressed the gas to a specified minimum. For royalty purposes, Calco wished to deduct 5 cents per mcf from the 12 cents received to reflect its costs of dehydrating and compressing the gas. The Secretary disagreed, arguing that Calco was obliged to bear that expense alone. To the court the question concerned the meaning of the statutory phrase "value of production."

> Does it mean the raw product as it comes from the well, no matter what its condition? Or does it mean that product readied for the market in and to which it is being sold?

296 F.2d at 387. The court observed that the lessee had an express duty under BLM's rules to "market' natural gas in order to avoid the "physical waste" of the production. Specifically, BLM required the lessee "to prevent the waste of oil or gas and to avoid

physical waste of gas the lessee shall consume it beneficially or market it or return it to the productive formation." 30 C.F.R. §221.35 (1959). Part of that duty to market the gas included the duty to put the gas in a condition acceptable to the "market, an established demand for an identified product." 296 F.2d at 388. "The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content." *Id.* While the court took care to explain that this case involved neither transportation not manufacturing costs, *id.* at 387, California Co. firmly established the principle that the lessee (at least one subject to the terms of former §221.35) had the duty to place production in marketable condition. California Co. was grounded on a regulation requiring the lessee (as one of three options) to market, but that duty applied only to natural gas. However, the other rules have expressed the duty as one also applying to oil.

When you later reach the point of fully exploring the duty to market, three principal lines of inquiry will need to be explored. The first is whether the Department is correct to rely on a lessee's "implied obligation to prudently market production...." ARCO Oil & Gas Co., 112 IBLA 8, 11 (1989). Federal lease forms contain no provision stating that the lessee has a duty to market production, let alone a duty to market free of cost to the lessor. MMS apparently relies on a duty implied in the leases to market the production for the mutual benefit of the lessee and lessor.

But that duty cannot be implied here, because the reason behind the implication of duties in an oil and gas lease is not present. The typical oil and gas lease is "silent about the obligation of the lessee with respect to the conduct of operations after oil or gas is first discovered." 5 H. Williams and C. Meyers, OIL AND GAS LAW, §801 (1985) (hereafter "OIL AND GAS LAW").

> The subject was, therefore, rationally left to the implication, necessarily arising in the absence of express stipulation, that further prosecution of the work [of development and production] should be along such lines as would be

> reasonably calculated to effectuate the controlling intention of the parties as manifested in the lease, which was to make the extraction of oil and gas from the premises of mutual advantage and profit.

Brewster v. Lanyon Zinc Co., 140 F. 801, 811 (8th Cir., 1905). The customary logic behind an implied duty to market is that without marketing of the production there will be no production or revenue on which the lessor can claim royalty; and the promise of royalties "was the controlling inducement to the grant" of the lease. *Id.* at 809.

MMS's quarrel here is not with a lessee's unwillingness to produce oil from a lease. It is instead with the value at which the lessee will pay royalties on oil it produces. And concerning the value of royalties, there is no room left between the lines of the leases and regulations for an implied duty to dwell. The Department has at all times had the option of taking the oil in kind and marketing it and has routinely done so. For most leases, it also has held the power, after notice and hearing, prospectively to set reasonable minimum values for the royalty on production. It has determined through regulations what the value of royalty would be and incorporated those regulations into the text of the lease forms it drafted. Therefore, it cannot be said that the parties to these OCS leases intended the questions of how marketing production is to affect the value of royalty to be governed by an implied generalized standard of reasonableness. "If the lessor's share of the oil, under the royalty provisions of the lease, is deliverable in kind to the lessor, the oil is theoretically under the control of the lessor and arguably he should be the one to market it, not the lessee." OIL AND 4 GAS LAW §853. Although Williams and Meyers "suggest" the lessee should still be under an implied duty to market production deliverable in kind, it is because, "[a]s a practical matter, . . . the typical lessor lacks both the experience and facilities to dispose of the oil produced . . . ." *Id.* Unlike the typical lessor, the Department has both the experience and, through the lease terms, access to the facilities needed to dispose of the oil. The lease expressly creates a duty in the lessee to provide the royalty on oil in kind, and MMS may market that share to its maximum advantage. The lessee, of course, is not responsible for MMS's costs of marketing in that setting. So the lease cannot contain an implied promise for the lessee to pay those costs when the Secretary takes his royalty share in value.

Another line of inquiry is to explore the implications of California Co. on the assumption that some express or implied duty to market exists, The preamble to the January 24 proposed rule relies on Walter Oil and Gas Corp., 111 IBLA 260 (1989), for its duty to market language. 62 Fed. Reg. 3742 (1997). There the lessee sought a deduction for the fee it paid an independent marketer to locate buyers, negotiate contracts, and monitor sales of gas produced from an OCS lease. IBLA upheld MMS's position, reasoning that Walter's purchasers were "willing to pay the contract price for the gas, and this price included the fees Walter paid to Commet (the marketer) for its services." 111 IBLA at 264. So, under the gross proceeds rule, IBLA found the fees for Commet's services to part of the total consideration accruing to Walter.

> The only allowances recognized as proper deductions in determining royalty value are transportation allowances for the cost of transporting production from the leasehold to the first available market.... A lessee may choose to employ its own personnel to find markets for its gas, or it may decide to hire an independent marketer to perform these functions. The lessee's business decision as to which method it prefers does not affect the value of the gas for royalty purposes.

Although this is standard logic for the Department, its flaw is evident. If the "duty to market" requires the lessee to bear all expenses of marketing, including the cost of conditioning production to meet the requirements of an established market, then the duty would also require a lessee to bear alone the expense of moving the production to an established market. Yet the Department has conceded at least since Shell Oil Co., 70 I.D. 393 (1963), that transportation costs need to be deducted from the proceeds of sale. If the obligation is to market, it is difficult to see the distinctions between transportation costs and other expenses attending marketing.

In ARCO Oil & Gas Co., 112 IBLA §8 (1989), IBLA rejected the analogy between deductions for transportation and those for other marketing expenses.

> The analogy sought to be drawn is unpersuasive, because it fails to draw upon similar circumstances. . . . But for the fact that the only market was onshore at a point distant from the lease, the transportation costs ... would not have been incurred by the lessee. . . . No allowance will be recognized by the Department where a lessee, as here, would have borne similar costs attributable to the creation and development of markets regardless whether production was sold on or adjacent to the lease.

It is helpful to apply IBLA's explanation to a few particulars. If oil is sold at the wellhead, a lessee bears administrative expenses of preparing sales contracts, proving sales meters, invoicing the purchasers, administering balancing agreements among its co-lessees in the reservoir, and the like. If oil is not sold until it reaches St. James, there are certain administrative costs incurred that essentially merely substitute for those that would have been incurred at the wellhead: preparing sales contracts, invoicing the purchasers, and administering balancing of production within the reservoir. But there are costs that would not have been incurred but for the movement of the oil off the lease. These might include premiums paid to insurance companies for policies covering the loss of oil during transport; inventory fees incurred at St. James; storage fees; costs of arranging and monitoring transportation; costs of monitoring and aggregating oil from multiple sources prior to sale; and so forth.

SECTION 206.102(g) - This provision again emphasizes that for MMS royalty valuation there can never be finality. Incredibly enough, the MMS asserts that even if it directs the lessee to compute royalties incorrectly, then the lessee will still be liable for underpayment and interest assessments for following the MMS's directive. This is true even if the audit period has been closed. MMS should at least include reference to the limitations imposed by the recently passed Royalty Fairness Act.

SECTION 206.102(h) - This section states that MMS will protect from disclosure information submitted by lessees under the new regulation proposed. This means that lessees will have transportation and location differential rates set by data which they will not be allowed to review or contest for correctness because it will be protected under the Freedom of Information Act. Promulgating a major regulation of this significance and denying access to the data to determine its validity is arbitrary, capricious, and an abuse of discretion.

SECTION 206.104 - TRANSPORTATION ALLOWANCES AND OTHER ADJUSTMENTS - GENERAL - Although MMS references reasonable, actual costs as defined under the current regulations, MMS does nothing to adapt the transportation regulations to the new valuation proposal. Since MMS has undertaken a major rulemaking to revalue oil and since transportation is an essential element to be deducted from that value to determine payment, MMS should also undertake to adapt those regulations to appropriately adjust value to reflect true transportation. FERC tariffs published by pipeline owners, even if affiliates, should be accepted as a reasonable, actual basis for transportation allowance of the producer for royalty purposes. For proprietary lines, MMS should be willing to accept the cost of comparable service paid by non-affiliated third parties to move through those pipelines. Acceptance of this as a royalty deduction for transportation was commonly approved prior to the 1988 regulations. MMS current proposal strikes §206.105(b)(5) which allowed the use of FERC tariffs as the appropriate deduction from royalty. The removal of this portion would mean that federal royalty oil is entitled to move at a below commercial rate. For regulated common carrier lines, it places the lessee in the awkward position of having to choose between violating a FERC tariff provision by charging royalty in-kind purchases a transportation rate below that of a published FERC tariff or subsidizing the transportation of royalty oil. A discounted transportation charge would likely result in a violation of FERC tariffs, orders, and regulations. There is no explanation given as to why (b)(5) should be removed. There is also no factual justification or statutory basis given for why the federal lessor now takes upon itself the mantle of some type of regulated utility entitled to special transportation treatment under its oil and gas contract. As previously noted, a federal oil lease has been characterized by the courts as no more than an ordinary contract. The statutes and contract of lease require the federal lessor to bear its fair share of reasonable, actual costs. Reasonable, actual costs as calculated under existing regulations provide only for depreciation on capital investment, the recovery of capital on undepreciated investment, and operating and maintenance costs. The return on undepreciated capital investment is set at the extremely low rate of Moody's BBB bonds. Once full depreciation of the pipeline has occurred, only operating and maintenance costs would remain. Defining reasonable, actual cost to be equivalent only to operating and maintenance charges is an arbitrary and capricious act of the agency.

Current FERC oil tariff setting procedures provide for a cost of service which, though regulated, remains constant throughout the pipeline's life. MMS starts with a higher rate but drops to almost nothing as a pipeline becomes depreciated.

FERC tariff setting methodologies may be briefly summarized and contrasted as follows. Rates for a new pipeline system are determined by getting an agreement on the rate from a non-affiliated shipper or by filing a cost of service filing. Rates on an existing pipeline system may be changed via annual indexing based on the Producer Price Index, a negotiated rate with all shippers ("settlement rates") through a market power determination study, or by a cost of service filing.

The starting point for a cost of service filing is to determine the pipeline's rate base which includes original cost of construction and an allowance for funds during construction (AFUDC, which represents cost of funds used for capital expenditures whether derived through debt or equity financing) less depreciation on original cost and an amortization of the AFUDC. Working capital (inventories and prepayments) can be added to the rate base and accumulated deferred taxes must be deducted. The rate base is divided into an equity and a debt portion based on the capital structure (debt/equity ratio) of the pipeline as of June 30, 1985 (because of restriction in the governing order this is usually the parent company's capital structure). The equity portion of the rate base is allowed an annual write-up based on an inflation index and the write-up (referred to as "deferred earnings") is also amortized over the pipeline's estimated remaining life.

As a result of this process, the pipeline's cost of service, or allowed revenues, is then determined based on the sum of the following:

1. A return on the total rate base based on a weighted average (using debt equity ratio) of cost of debt and a real return on equity capital. Return on equity should be commensurate with returns on investments in other enterprises having corresponding risks; real equity returns on recent filings have ranged between 10 and 12 percent. MMS has no procedure to accomplish this.

2. An income tax allowance based on the return on equity rate base plus amortization of the deferred earnings plus amortization of the equity portion of AFUDC multiplied by the pipeline's effective income tax rate divided by one minus the effective income tax rate.

3. Total pipeline operating and maintenance costs including depreciation, administrative costs, and taxes excluding income. MMS totally rejects tax as a cost of business.

4. Amortization of the deferred earnings in the equity rate base and amortization of the AFUDC in the debt and equity rate bases.

Under MMS's proposal, a producer would move through a producer affiliated common carrier at a lower rate than an arm's-length unrelated party. For example, Producer X may be entitled to charge only 10¢ a barrel of O&M costs while an unrelated producer moving federal government oil through the same line would be entitled to take a full 50¢ charge. The federal lessor must bear its full cost of actual service performed. That cost is reflected either in the tariff or the cost of comparable service paid by unrelated third parties to move through a pipeline system. Structuring transportation rates to provide for this minimal return is a disincentive to lessees to create the necessary infrastructure required to transport oil from the offshore location to shore. To take this position would be analogous to requiring a public transit system to cease charging for movement in any buses or subways which had been fully depreciated and to base the cost of transportation only on actual operating and maintenance expenses of the bus or subway. As set out above, even the FERC allows a reasonable rate of return considering risks of the business enterprise and an adjustment periodically to reflect depreciation.

SECTION 206.105 - DETERMINATION OF TRANSPORTATION ALLOWANCES AND OTHER ADJUSTMENTS - Subpart C - This provision provides for a required adjustment to the index price for reasonable location and quality differentials and an optional adjustment for transportation to reflect value differences between the lease, which could be hundreds of miles offshore, and the index pricing point which is designated as Cushing, Oklahoma, for Gulf of Mexico production.

Pursuant §206.105(c)(2), Gulf of Mexico lessees are to determine transportation costs in accordance with final disposition of the product. Section 206.105(c)(1)(i) provides as an option a location differential determined by comparing the value of crude oil at the index pricing point and the appropriate market center. It is calculated by comparing the average spot price in approved publications specified by the MMS to the price of the same crude at the index pricing point. In practice, since NYMEX references only sweet NYMEX crude, this would require comparison of spot price of a crude type at Cushing, Oklahoma, to the same quality of crude in question at a market center like St. James/Empire. That difference will then be added or subtracted from NYMEX sweet crude price to arrive at value of a specific gravity Gulf crude at the market center. It is arbitrary and capricious to presume that the difference between spot prices of various crudes which are base valued in a publication like Platts is able to derive a delta which can be added or subtracted to the NYMEX sweet value to provide a location adjusted NYMEX sweet value for the crude type at a market center. Stated another way, if the base price of Platts for the particular type of crude is adequate to determine the differential to be applied to NYMEX sweet, why would not the Platts spot price at St. James/Empire be adequate in and of itself to determine value? (Each is equally arbitrary. There use demonstrates how arbitrary the MMS proposal is.) Two different publications based on separate market risks are compared to give a third value at the lease. In any event, calculation of a location differential using this proposed method is inadequate to compensate the lessee for the differences in price attributable to NYMEX sweet crude delivered at a major interconnect point with substantial storage facilities such as Cushing, Oklahoma. We have previously discussed the substantial differences in security of supply; credit worthiness; and shift of risk of fire; explosion; and weather not present in futures contracts which are present each day affecting physical delivery of oil at the lease. MMS has demonstrated no logical factual basis for making a market adjustment which inadequately compensates the lessee for using a price far removed from the lease which represents substantial enhanced value.

SECTION 206.105(c)(1)(ii) - This allows the use of the arm's-length exchange agreement that reflects the difference in value of crude oil at the aggregation point and the market center. This proposal presents substantial problems. The lessee does not necessarily calculate transportation by reference to aggregation points specified by the MMS. Portions of the transportation will be accomplished in various segments of the pipeline which may occur either before, after, or across the aggregation point or the market center references or both. Since movement through tariff lines is calculated purely by reference to the tariff per barrel for moving through the pipeline system, and since the movement by transportation exchange agreements is calculated by a sale and resale at specified points, neither of which necessarily includes the aggregation point or market center, it is completely unclear how the transportation costs would be proportionately identified in order to provide necessary information for determining the allowance. This provision simply will not work since transportation does not occur as MMS has arbitrarily presumed.

SECTION 206.105(c)(1)(iii) - This provision provides for use of a volume weighted average of differentials for location and quality determined by reference to form MMS 4415 for movement from the index pricing point to an aggregation point. In effect, this provision deprives the lessee of the opportunity to deduct actual transportation cost from the market center to the aggregation point. Instead, an estimate is somehow to be calculated by the MMS from Form 4415 based on historical prior years data. This is plainly arbitrary and does not reflect actual cost of transportation which the lessee is entitled to deduct. A review of Form 4415 leaves the lessee in total darkness as to how the location/quality differential is to be calculated. The sample to be utilized will rely exclusively upon non-arm's-length transportation exchange agreement data. The aggregation points in question may or may not be the point of transfer. The data solicited is from data all over the United States for both private as well as federal leases. There is no demonstration that this data has any relationship to the cost of moving actual physically severed barrels of oil from the aggregation point to the market center. The cost of constructing pipelines onshore is substantially different from the cost of laying offshore pipelines on the floor of the Gulf of Mexico. Inclusion of data based on onshore calculations of data is plainly arbitrary. Eliminating all of the transportation done by affiliate owned pipelines substantially reduces the sample on which the average will be calculated. MMS has presumed that quality adjustments are always made in transportation agreements. This is not the case. Quality adjustments are a function of market conditions. MMS has plainly gone far beyond the bounds allowed by reasonable discretion in determining value. Valuing lease quality crude at averaged aggregation point quality will have no relation to actual quality value and is plainly arbitrary. Aggregation points have not been demonstrated to be significant points of valuation under any existing publicly available indices other than the mechanical and arbitrary process created to net NYMEX back to the aggregation point itself. Location differential is not even adequately defined by the MMS to include appropriate adjustments reflecting the costs and risks of operating pipelines and moving physically delivered oil from an aggregation point to a market center. Since the information used to calculate the sample will be considered proprietary and confidential, lessees will not even be able to adequately challenge MMS's determination. Clearly, this places the lessee in an untenable position. The use of historical rates based on preceding years data clearly has no relationship to actual cost paid to move through a pipeline on the day of physical severance. Crude types are known to vary from month to month. The Gulf of Mexico Regional Office requires periodic quality tests at the royalty settlement point in order to clearly establish quality for royalty determination purposes. Use of the preceding year's data based on qualities which were in effect for actual exchange agreements between non-affiliated parties will not be reflective of the quality of oil physically moved today. Use of a single average quality to value all oil moving in the system will be arbitrary. It will not reflect value as produced and measured in accordance with MMS Gulf of Mexico operations directives on royalty which require royalty to be paid on the amount and quality at the specified royalty settlement point.

SECTION 206.105(c)(1)(iv) - This provision provides for actual transportation costs from the aggregation point back to the lease. However, many of the aggregation points identified by the MMS lie beneath the Gulf of Mexico at pipeline interconnects. Current transportation arrangements do not necessarily reflect receipt and delivery at these aggregation points themselves. It would be impossible for the lessee to determine what portion of the transportation was attributable to a segment of transportation from the lease to the aggregation point when a total cost was paid to move to a point beyond the aggregation point. Since lessee did not build the line, lessee would be unable to know distances in order to prorate cost even if a value per mile were determined. In addition, the rule as proposed ignores the realities of capacity restrained pipelines, particularly those carrying substantial quantities of deepwater production. In order to secure transportation to shore it is often necessary to flip flop from month to month to various pipelines with different aggregation points. Under these circumstances, last year's historical data may bear absolutely no relationship to the quality and cost of transportation based on pipeline capacity availability for today's production. The reasonable, actual cost prescribed by the existing regulations are, as previously discussed, inadequate to compensate the lessee for the cost of transportation and result in the federal lessor's portion receiving transportation at a substantial commercial discount. This discount could, for common carrier tariff oil lines, actually violate the tariff for royalty in-kind production. At best, it seems inappropriate for one federal agency to determine fair value for movement and the other to deny that that value is fair.

SECTION 206.105(c)(2)(ii) - This provision addresses production which does not move through an MMS aggregation point or market center, but instead moves directly to an alternate disposal point such as a refinery. Under this scenario, the alternate disposal point (the refinery) becomes the equivalent of the aggregation point, and the lessee is directed to identify the market center closest to the lease where there is a published spot price for crude of like quality. Presumably the NYMEX sweet price will be adjusted by the differential of the spot price at the market center and then a location quality differential made to the alternate disposal site as if it were an aggregation point. Under this scenario, only the location/quality differential specified for the aggregation point is allowed, and no transportation costs actually incurred is allowed as a deduct. This process again ignores the market adjustment which should be made to reflect the differences between NYMEX futures commodity prices and the price of a physical barrel of oil delivered in a field at the lease. If the refinery has not been identified as an aggregation point, it is unclear under the regulation how a lessee would be expected to calculate or find a matching aggregation point for the market center chosen based on MMS publications. In any event, lessees would have the same difficulty in utilizing this averaged location/quality data because it has the same flaws described above and incapable of verification.

<u>SECTION 206.105(c)(2)(iii)</u> - This provision provides for a situation when oil moves directly to a market center but does not cross an aggregation point. In this instance, the lessee is allowed to deduct actual transportation costs to the market center as determined under the regulations. It appears completely arbitrary on the part of the MMS to provide for MMS defined actual transportation cost to the market center when the oil moves directly to the market center but to deny use of reasonable, actual cost when oil passes through an aggregation point. No explanation for the difference is adequately presented. Location differential is not adequately defined and an inadequate adjustment for the difference between NYMEX future commodities market and the physical lease market is not made. Spot price for like quality crude is required but how it is to be used is not explained. No quality adjustment is made or allowed from the market center spot location to the refinery itself.

<u>SECTION 206.105(c)(2)(iv)</u> - This provision will apply to most of a federal lessee's production, particularly in the Gulf of Mexico. It specifies that a lessee will get a location differential at the market center based upon something like the difference between Platts quotes for various crudes as added or deducted from NYMEX sweet at Cushing. Next, the lessee will receive the weighted average Form 4415 calculation for location and quality differential from the market center to the aggregation point. Finally, the lessee will be allowed to deduct reasonable, actual cost from the aggregation point back to the lease. All of the difficulties previously noted are applicable to this procedure which will cover the majority of Shell and other producers' oil in the Gulf of Mexico. A location differential at St. James/Empire market center based on approved spot price publications is inadequate to compensate the lessee for differences between the futures commodities market and the risks involved in physical severance and movement of oil to market on a daily basis. Neither of the indices, NYMEX or spot, are directly tied to lease market risks. There is no explanation of the logical connection between a calculated difference of spot prices at market centers which is then deducted from NYMEX to reflect some type of a market adjustment appropriate to physical severance of minerals. This provision provides a certain math calculation, but it has no relationship to value of oil as physically severed at the lease. The data base to be used to determine the weighed averaged location/quality differential from market center to the aggregation point is also flawed as previously explained. The sample data base is derived only from non-affiliate sale exchanges and excludes all production moved through affiliated producer pipelines. It includes oil moved by affiliates all over the United States which has no relationship to quality/location differentials in the Gulf of Mexico. It provides no justification for equating location differential to actual transportation cost incurred; provides for an arbitrary and unlawful determination of reasonable, actual cost by eliminating the use of tariffs; and rejects the cost of comparable service paid by non-affiliated producers to move through the same pipeline. One of the major defects of subsection (iv) is that it contains no adjustment for quality back to the lease itself. All adjustment to NYMEX index value stops at the aggregation point. Therefore, contrary to Gulf of Mexico operating directives, lessees will pay royalty on volume but not on a quality measured at the lease settlement point. A quality measurement at the lease will be made, but royalty will be paid on the average quality at the aggregation point. Current postings provide a discount for gravity and sulphur content per degree and percentage of sulphur back to the lease. Since NYMEX itself contains no table of adjustment, MMS has found it necessary to reference NYMEX to spot prices of approved publications at major market centers but has failed to extend that price adjustment for value from the market center to the aggregation point and on to the lease. This leaves a substantial gap in the regulations and application of NYMEX to lease value upon physical severance.

SECTION 206.105(4) - This provision deals with situations in which the MMS calculated differential does not apply to a lessee's oil either due to location or quality difference. It requires lessee to request the MMS to calculate the differential. However, in order to invoke this paragraph, the lessee must provide clear evidence demonstrating why the published differential does not adequately reflect its circumstances. With substantial volumes of deepwater production scheduled to come on line over the next four to five years, it is obvious that this provision will have great application. Failure to make a request for a calculation by the MMS imposes a penalty of interest assessment on underpayments but denial of refunds for overpayments. This process appears to be, at a minimum, contrary to the spirit of the Royalty Simplification and Fairness Act. The penalty imposed on a lessee appears to exceed the seriousness of the offense, particularly when an overpayment has resulted. No harm for overpayment will occur to the MMS since they will have had use of the money during the entire time period.

SECTION 206.105(4)(d)(iii) - This provision purports to require not only the federal lessee, but also their affiliates, to submit MMS Form 4415. MMS has no authority under statute to require the submission of forms on a routine basis by non-lessees. The instructions attached to the form exhibit of the regulations requires reporting irrespective of whether the exchange takes place at the lease or downstream of the lease. Subpart (d)(iii) requires information filings not only on federal lease production but also on private lease and state lease production. This provision is plainly arbitrary and capricious since it exceeds the statutory authority of the agency for data collection. The sample case includes only contracts where oil is exchanged between non-affiliated parties. As a result, all producer owned proprietary transportation is excluded from the calculation base. Call production is excluded without any reference to whether the call price or transportation arrangement are equal to or in excess of other third party transactions. Requiring data on exchange agreements entered into away from the lease exceeds the authority of the MMS. It is impossible for lessees or affiliated marketers to distinguish portions of commingled streams to identify what barrels of oil are associated with what leases. The time required to complete the form is grossly understated since, for exchange agreements, completion of the form will require a specific detailed analysis of each contract term. It will take far longer than 15 minutes to simply read, digest, and summarize individual exchange agreements. The information sought is not readily available any place. MMS has assumed that a ready database may be sourced for this information. This database does not exist but will need to be manually created. The information is not known by one group or person but, in the case of Shell, involves several different corporations, each of which is separate and distinct, each of which has different employees, business missions, and record keeping procedures. Payors simply don't have access to information requested in the form. No direction is given on distinguishing private, state, or federal production; movement through multiple several aggregation points; or handling of call crude production. Since much of the data collected will not even reference the aggregation points specified, it is believed that much of the data gathered will be in a form useless to the MMS. It is unclear how the MMS will utilize data gathered from private and state leases to calculate location and quality differentials for leases located hundreds of miles offshore. The markets themselves are different, the risks different, and the transportation pipelines leading to market disposal different. Intermixing onshore and offshore location and quality differentials appears to make little sense. Confidential and proprietary nature of the data collected on Form 4415 will make it impossible for Shell and other lessees to validate MMS calculations. The data requested will be frozen as historical data of the preceding year but applied to current year's production. Since quality measurements of offshore oil change monthly and even the MMS Gulf of Mexico office requires periodic quality test for royalty purposes, the historical data will bear no relationship to present day production.

SECTION 206.105(g) - MMS has revised this section to eliminate actual or theoretical losses which had been provided by oil tariffs. Although the FERC has approved the inclusion of these losses in tariffs, the MMS has now taken a firm position that even when losses have been included in a tariff, they may not be taken by a lessee since the lessee cannot use the tariff. However, the MMS will allow losses to be taken when they are included as part of the terms and conditions of an arm's-length transaction. For present common carrier pipelines, this means that non-affiliated third parties moving through the line will be entitled to take losses since transportation will be at tariff but the lessee moving through its own affiliated pipeline will be denied the opportunity to do so. For proprietary owned non-common carrier lines, actual or theoretical losses included in the transportation/exchange agreement will be allowed if part of the arm's-length transaction, but the lessee will be denied a deduction for similar losses for its own affiliated production moving through the line.

SECTION 208.4 - ROYALTY OILS TO ELIGIBLE REFINERS - This provision requires value determination by NYMEX index regardless of whether oil produced from the lease would be valued for royalty purposes on that basis. In short, it makes NYMEX index as adjusted by the MMS proposal the binding value for royalty in-kind production. Transportation cost will be determined in accordance with the same regulations. All of the comments previously made regarding the arbitrary and capricious nature of the use of NYMEX apply equally to valuation of in-kind oil sold by the MMS to small and independent refiners. However, the transportation regulations would require that royalty in-kind oil purchased by an independent refiner move through common carrier lines at a rate below the tariff charged other parties in the line under old form MMS leases. This will create substantial regulatory problems for the lessee and its affiliated pipeline operator. In short, it will require the lessee to violate existing FERC regulations and its tariff in order to obey MMS royalty regulations. If the royalty in-kind program were to be expanded then in the present reality of world over supply, any expansion of the royalty in-kind program should be coupled with an expansion of those parties eligible to purchase royalty in-kind production. In addition, providing royalty in-kind should fully and finally satisfy all royalty obligation. Delivery of any expanded royalty in-kind program should be at the lease and not at an onshore point.

LACK OF CONDENSATE COVERAGE - The valuation of condensate as crude under index pricing is absent. MMS in its rush to press has totally neglected to include any valuation directive for condensate production. 30 CFR §202.100(a) discusses royalty on oil and requires condensate separated from gas without processing as a product determined under the oil valuation regulations. Lessees have been given no opportunity and no guidance on how to value condensate derived from gas pipelines under this NYMEX proposal. MMS must republish the regulation in order to provide an opportunity for lessees to comment on the unique aspects of condensate valuation using NYMEX commodities futures as a valuation basis.

INTERIM FINAL RULE - MMS has also mentioned the possibility of publishing an interim final rule while it digests the comments submitted on this valuation proposal. As can be seen from the numerous gaps, conflicts, and ambiguities in the regulations as drafted, implementation on an interim basis is inappropriate. The cost to MMS to adjust current systems to these proposals as well as the costs to industry to implement the regulation when they are riddled with deficiencies clearly militates against immediate action. Lessees should be given an opportunity to review condensate valuation before it is implemented in order to fulfill minimum requirements of the Administrative Procedure Act. In addition, the radical departure from precedent embodied in the concepts expressed in the rule will likely lead to litigation which may extend over a protracted period of time. MMS has hardly given industry enough time to digest and understand the regulations before making comments. For the agency to now rush to interim publication with the associated cost for both government and industry would be imprudent.

EXHIBIT A

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
P.O. BOX 25165
DENVER, COLORADO 80225

IN REPLY REFER TO:
MMS-RVS-EVB:86-1088
Mail Stop 653

FEB 12 1987

Memorandum

To: Director, Minerals Management Service

From: Associate Director for Royalty Management

Subject: Review of Analysis Titled "Crude Oil Royalty Valuation Monitoring System," by Bob Berman, Policy, Budget, and Administration

By memorandum of November 21, 1986, the Deputy Assistant Secretary, Policy, Budget, and Administration (PBA), suggested to you that further study be done of market-based approaches to royalty valuation under non-arm's-length conditions. He included an analysis dated November 28, 1986, by PBA's Bob Berman, who suggests the application of oil futures or spot prices as an alternative valuation methodology. Our comments on this analysis have been requested.

It is obvious that considerable thought and effort have gone into Mr. Berman's analysis. However, the inescapable conclusion is that, for purposes of oil royalty valuation, the application of futures and/or spot prices would be either contrary to existing law, lease terms, and regulations, or too impractical and nonspecific to administer. Listed below are our specific comments:

-- The Mineral Leasing Act of 1920 (Section 17(b) and (c)) states that royalty shall be based on the amount or value of production removed or sold from the lease. The Outer Continental Shelf Lands Act of 1953 (Section 6(a)(8)) states that royalty is due on the amount or value of production saved, removed, or sold. There can be little doubt that the value of production removed or sold was intended to be the current value, for which a futures price would be inapplicable.

-- Similarly, the various Federal and Indian leases require royalty on the amount or value of production removed or sold. Once again, futures prices would not, except coincidentally, reflect values of production sold currently.

-- The existing regulations dealing with oil valuation, both onshore and offshore, address value of production, at the time of production or sale, for computing royalty. The regulations at 30 CFR 206.103 (onshore) state that, in the absence of good reason to the contrary, value based on the highest price paid or offered at the time of production for the major portion of like-quality products from the same field or area will be considered reasonable value. Similarly, the regulations at 30 CFR 206.150 (offshore) state that "Under no circumstances shall the value of production be less than the gross proceeds accruing to the lessee. . . ."

These regulations require leasehold oil production to be valued as of the time of production and/or sale. Hence, any attempt to apply a futures price for royalty value purposes would necessarily incorporate the market's assessment of the level of oil prices at some future date. Obviously the futures prices would not necessarily be reflective of current market price levels as required by regulation.

Though it may be suggested that current regulations could be changed to effect changes to royalty provisions of future leases, it is important to note that such rulemaking would need to conform with existing statutes. As previously mentioned, existing statutes indicate a royalty based on current value. Consequently, a change in statutory, as well as regulatory, language may be necessary to issue new leases with royalty provisions tied to futures values.

-- Application of spot prices in valuing non-arm's-length disposals of lease production would not be specific. Spot prices are available only for a limited number of "benchmark" domestic crudes delivered at specific points; e.g., West Texas Intermediate at Cushing, Oklahoma. It is not clear how spot prices would be adjusted for differences in quality or necessary transportation between that of the "benchmark" crude and that of the crude to be valued. An adjustment for differences in API gravity alone, for example, while a reasonable price adjustment mechanism for oil produced in the same field or area, does not necessarily reflect true value differences when comparing crudes from distant areas. The price differences in crude oil nationwide depend upon a host of factors not limited solely to gravity and transportation adjustments. Factors important to the establishment of value of a particular crude include the need for and availability of crude oil supply, the cost of transportation to the refinery, the chemical composition and refining characteristics of the crude oil, the cost to refine the particular crude, the mix of refined products derivable from the crude and their values, prices currently paid or offered for the same or comparable crudes, and other economic criteria. Posted prices, which exist in all the important producing areas, reflect all these considerations; "benchmark" spot prices, on the other hand, cannot relate these factors specifically to each producing area. The same is true for futures prices, which also relate to a few "benchmark" crudes only.

-- Mr. Berman's analysis speaks to "market-based" alternate valuation procedures; i.e., futures and/or spot prices. The implication that posted prices are not market prices is, of course, true to the extent that postings are offers to buy and do not always reflect prices actually paid. Postings are, however, driven by the market, are sensitive to market changes, and are adjusted as market conditions require. While posted prices may, on occasion, vary slightly from actual market prices, they are undoubtedly market based. The MMS would be hard pressed to defend a position that futures prices are better, more accurate, and more current measures of royalty value for current production than are concurrent posted prices.

-- Posted prices are widely available. They exist for nearly all fields and areas for which royalty valuation is necessary. Further, since a field posting relates to oil with the same general quality characteristics, quality-based price adjustments are simple and accurate. The same cannot be said for application of spot or futures prices for royalty valuation purposes.

-- A real inconsistency would develop if prices received under arm's-length conditions were accepted for royalty valuation purposes while futures prices were applied to non-arm's-length transactions. Two entirely different valuation standards would exist. (We agree that non-arm's-length transactions should receive a higher monitoring priority, and generally be investigated more thoroughly than arm's-length transactions. However, the standards to which each type of transaction is held should be as similar as possible.) If arm's-length prices are acceptable for royalty valuation purposes, a reasonable proxy for current non-arm's-length prices is not a futures price, but, rather, an assessment of what is currently being obtained under arm's-length conditions.

In summary, even though Mr. Berman's analysis is a scholarly study which provides insight into the workings of the oil futures market, we must disagree with the application of oil futures or spot prices as a basis for royalty valuation in non-arm's-length situations. We have ignored the fact that the study covered a relatively short period of time (15 months) during which extreme pricing volatility took place, and we have not discussed other, more minor disagreements we have with the study. More important is the basic conclusion that, even if the study results do indicate that oil futures prices "lead" posted prices, this has no bearing on our valuation responsibilities. For royalty valuation purposes, we must apply market value existing at the time of production or sale. Whether postings are considered to lag futures prices or not, postings represent current offers to purchase oil and are adjusted as necessary to conform to market conditions. Further, oil futures and spot prices are available on such a limited basis as to make price adjustments for quality and/or transportation extremely difficult, if not meaningless.

It has been our policy in non-arm's-length situations to verify that the posting or other price to be applied for royalty purposes is consistent with prevailing arm's-length prices. This policy is, we feel, rightly extended in the proposed oil royalty valuation regulations. The continued acceptance of arm's-length postings or contract prices is seen as the most equitable, most practical, and most easily administered method of royalty valuation available. The widespread existence and acceptance of posted prices make them much more applicable to specific cases than oil futures or spot prices, both in terms of timing and necessary adjustments.

Jerry D. Hill